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Possibilities of hydropower to balance wind power on the Nordic electricity market

Thesis submitted for examination for the degree of Master of Science in Technology.

Espoo 09.02.2021
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Abstract

Nordic governments are committed to the international greenhouse gas (GHG) emission reduction agreements. Due to the advanced externality mitigation policies, the share of wind power in the Nordic market area has grown 10-fold during the 2010s and a further doubling of the total wind power generation capacity is planned to be implemented by 2030. Furthermore, the Nordic electricity system has an exceptionally high share of hydropower, 51% of the total gross generation in 2019. The hydropower production and storage in Norway and Sweden is expected to provide valuable regulating power in the Nordic electricity market as the share of variable renewable energy sources (RES, e.g. wind power) increases. This study focuses on analyzing some of the alternative 2030 development scenarios for the Nordic electricity system and market. The changing scenario variables include forecasted electricity prices, generation mix and pumped hydro storage capacity. The energy market scenarios are modeled with EnerAllt, a MATLAB-based energy system model, which is used to model on hourly basis the energy system operation, consequent bidding area prices and exchange flows by considering the transmission line limitations between bidding areas. Therefore, this thesis provides bidding area resolution insights about the economic and technical impacts of the most ambitious RES expansion plans available for public in the Nordic electricity market. The goal of the thesis is to provide realistic estimates of the share of wind power that can be integrated to the Nordic energy system without the need for system level investments. The impacts of bottlenecks in transmission are analyzed and recommendable priorities for further transmission investments are indicated.

Keywords Nordic energy markets, wind power production, hydro reservoir, interconnectivity, bottleneck, congestion, integration, storage, transmission

Preface

The interest towards mitigating the acceleration of climate change has raised interests in scenario modeling of the demand, transmission and production profiles in the international energy markets. Nordic countries have started building and planning to replace much of the fossil energy sources with wind and hydro power. This thesis uses the Aalto University EnerAlt-model to simulate and analyze scenarios with rapid increase in wind power within the Nordic electricity markets. Alternative scenario models aim to find thresholds for wind power production capacity, interconnector capacity, Nordic hydropower reservoir capacity and the role of alternative low-emission electricity production.

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I want to thank the whole science community and the brave energy industry leaders who pioneer the transitions towards more sustainable, scalable and safe energy services.

Espoo 09.02.2021

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Units

Name	**Unit**	**Explanation**
kW	kW	kilowatt
kWh	kWh	kilowatt hour
MW	MW	megawatt
MWh	MWh	megawatt hour
TW	TW	terawatt
TWh	TWh	terawatt hour

Abbreviations

aFRR	automatic frequency restoration reserves
BWR	boiling water reactor
CHP	combined heat and power
DH	district heat
DSO	distribution system operator
EC	European Commission
EU	European Union
EU-JRC	European Union Joint Research Center
FCR	frequency containment reserves
FCR-D	frequency containment reserves for disturbances
FCR-N	frequency containment reserves for normal operation
GHG	greenhouse gas(es)
ICE	internal combustion engine
MC	marginal cost
mFRR	manual frequency restoration reserves
PP	power plant
PV	photovoltaic
RES	renewable energy sources
RSI	residual supply index
SC	storage capacity
TSO	Transmission system operator
UN	United Nations

1 Introduction

1.1 Background

Nordic countries have pledged to contribute to mitigating global warming below 2˚C above pre-industrial levels at the 21st Conference of the Parties (COP21) to the United Nations Framework Convention on Climate Change (UN/FCCC 2015) in Paris. The Paris Agreement agrees global collaboration to keep the increase of global average temperature to below 2°C, while striving to maintain it at 1.5°C above pre-industrial levels. To accomplish the goal, participating parties set the GHG emissions to peak as soon as possible, and commit to achieve net-zero emissions by 2050 (NFCC 2016).

Nordic governments have also pledged interest towards climate-friendly Nordic energy transition collaboration (Norden 2016) and Nordic Transmission System Operators (TSO) have an extraordinarily close collaboration through a mutual balance market platform venture named eSett (eSett 2020).

According to the EU Reference Cases 2016: Trends to 2020 the Nordic power sector related emissions of the total emissions are listed in the Table 1 below.

Table 1. Power sector related emissions in the Nordic countries, including Denmark (DK), Finland (FI), Sweden (SE) and Norway (NO) [Energie Fakt Norge 2018]

Country	2020 (Mt CO2 / Total)	2020 power sector share of total emissions	2030 (Mt CO2 / Total)	2030 power sector share of total emissions
DK	7,2 / 45,8	16 %	6 / 41,2	15 % (-1%)
FI	19 / 59,1	32 %	17,3 / 51,3	34 % (+2%)
SE	6 / 54,2	11%	6,1 / 47	13 % (+2%)
NO	0,02 / 53,9	5 %	0,02 / 53,9	5 % (+0%)

Electrification of district heating, industrial heating processes and transportation will keep the share of emissions from the power sector rather stable while enabling emission reductions in the other energy service sectors. Demand for heat represents around 50% of the total energy demand in the Nordic Energy Markets (EC 2016).

To enable the emission reductions in other segments of the energy sector more electricity generation with less emissions is required. Available current low greenhouse gas emission sources for generating electricity are hydro, nuclear, wind, solar and geothermal energy and also biofuels are currently accounted partially as emission-free energy sources in the EU Emission Trade System (EP 2015).

The goal of the Nordic energy strategy is based on reducing greenhouse gas emissions by lowering the emission intensity of the generation processes. This is done by increasing the share of low-emission electricity generation in the energy mix and via fuel switching from coal and oil to less GHG emitting fossil fuel sources such as natural gas and renewable and synthetic fuels. The alternative energy road maps to solve these issues vary in the weight on different generation, transmission, consumption, and storage methods.

Each Nordic country has had renewable electricity generation capacity investment subsidy schemes such as the Swedish and Norwegian green certificate scheme (NMPE 2019) and the Finnish law, Act on Support for the Production of Electricity Produced from Renewable Energy Sources §1396/2010. These subsidies have been established to accelerate the increase of the share of VRES in the energy mix.

Nordic electricity market already has a significant penetration of renewable sources. In 2019 hydropower represented 51% of the total Nordic electricity generation and the capacity of wind power have 10-folded from 5600 MW, representing 6% of total electricity generation (NordReg 2011); to 20 000 MW, representing 19 % of total generation (Svensk Vindenergi 2020) during the 2010's with no hindrance on sight (ENTSO-E TP 2020). Hydropower provided especially significant share of electricity in Norway, totaling 141 TWh/a. This represents 94,3% of Norwegian production and 50% of Europe's water reservoir capacity, in the period 1990–2015 (Norwegian Ministry of Petroleum and Energy 2019). This study assesses the potential of hydropower and transmission reinforcement plans to balance the projected increase in the share of wind power in the Nordic electricity market's development plans.

1.2 Research Questions

This study simulates alternative wind scenarios for the Nordic Electricity Market with and without an increase in the availability of Pumped Hydro Storage (PHS) capacity. The goal of the study is to evaluate the possible need and potential of Nordic hydropower to balance the increased share of wind power in the Nordic power system. The modeling also indicates if the existing Nordic wind power capacity increase scenarios function harmoniously with the Nordic transmission system development plans. The study aims to identify potential bottlenecks in the market area transmission network and the possibility of PHS to reduce the need for transmission capacity increase.

The research questions can be summarized as;

1) *How do the different wind scenarios affect the projected market prices of electricity?*

2) *How does the inclusion of PHS capacity affect the market prices of electricity in different scenarios?*

3) *How well do the existing transmission capacity development plans respond to the transmission needs of the suggested wind power scenarios?*

1.3 Scope and limitations

Scope of this study is limited to Nordic Electricity Market, focusing especially on Norway, Sweden and Finland. Each country is divided according to the electricity market bidding areas specified in **Error! Reference source not found.**.

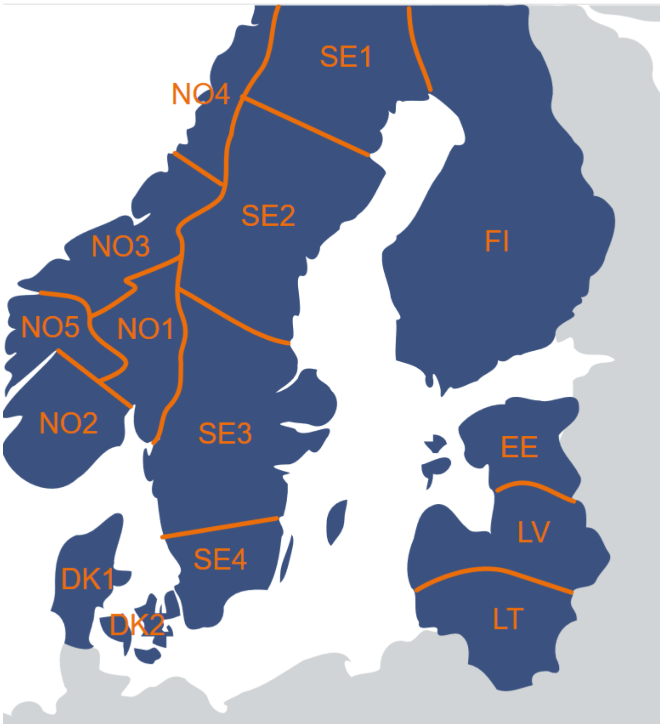

Figure 1. Nord Pool bidding areas (Nord Pool Group 2020)

The bidding area resolution demand, domestic generation mix profiles and interconnectors are modeled to obtain more detailed results about the potential PHS opportunities and transmission constraints emerging from the increasing ratio of VRES in the electricity generation mix.

The model simulates the operational adjustments of generation mix in the Nordic bidding areas in relation to the balance between the domestic demand, domestic supply, generation prices and transmission exchange conducted within the limitations created by the connected bidding area electricity spot prices and interconnector capacities.

Forecasting the future energy prices is challenging due to the complex nature of energy price formation. The challenge of real time balancing of supply and demand is made more challenging through variables such as temperature changes, differentiating precipitation patterns, efficiency development of generation units, price development of emission allowances, general global economic development, global and international legislation affecting the energy service sector and cost-efficiency development of fuel supply chains; all can have major impacts in the electricity prices within any 10 years observation period. In this study the changed variables are limited into changes in the Nordic electricity generation mix and interconnector capacity. In reality much more will change during the next 10 years. This modeling work aims to help in finding what type of impacts will the various suggested generation scenarios have within the Nordic electricity market.

It is also a complex challenge to identify which mix of power infrastructure improvements would be technically, economically, socially, and environmentally most feasible in the regional development context. The large range of stakeholders are divided into various interest groups and gaining a broad consensus for large-scale long-term solutions is an ongoing iterative research and negotiation process. This study's main focus is on researching the limitations of physical electricity transmission capacity in variable renewable energy source intensive generation scenarios in the Nordic electricity market.

2 The effects of variable renewable energy generation on energy system operation and possible balancing solutions

Nordic countries have reached a political agreement on the collaboration for developing an integrated low-emission electricity system which utilizes large shares of renewable energy sources. As a part of the European Governance Regulation each European government has made a National Energy and Climate Plan 2020 (NECP) to report each country's climate and energy objectives, targets, policies and measures to the European Commission (EU/2018/1999).

According to the Paris Agreement commitment, EU aims at reducing GHG emissions by at least 40%, increasing the share of renewable energy to at least 32% and guaranteeing interconnectivity level of 15% between neighboring Member States (UNFCC 2016). According to the NECPs Sweden aims at exceeding the EU 2030 goals by raising the share of renewable energy to 65% of final energy consumption (and to 100% by 2040), interconnectivity level to 27% and intensifying the cooperation arrangements between Nordic countries in the areas of market integration and energy security; while extending this cooperation to Baltic States (NECP SE 2020). Norway aims to develop cost-efficient technology for carbon capture, transport and storage (CCS). Biofuel blending is set at 16% in 2020 and biogas-project development will be publicly supported (NECP NO 2019). Finland aims to increase the share of renewable energy to 51% of final energy use and the share of renewable energy to 30% of final energy use in road transport. Energy efficiency targets set the cap for annual final energy consumption to 290 TWh. Continue the Nordic electricity market cooperation to further strengthen its high level of security of supply, an equal competitive playing field, environmental friendliness, transparency and incentives for price elasticity (NECP FI 2019). Due to these commitments the Nordic Electricity market is considered as an integrated system in all of the assumptions in this study.

2.1 Nordic Electricity System

Nordic Electricity Market has been unified to a single market area, where the participants are allowed to freely – in the limits of generation, load and transmission capacity constrains – bid for electricity purchases and sales in ongoing day-ahead, intra-day, regulation and balancing market auctions (NordREG 2014). While the electricity auction exchange has been operated by Nord Pool Group as a monopoly from the year 2000, in June 2020 two other exchange operators EPEX SPOT and Nasdaq have received permits to operate as electricity exchanges in the Nordic electricity market (Fingrid 2020). Collaborative efforts to enable the development of new energy service markets are developed through joint programs aiming to further open the markets for new market participants.

To ensure the technical transmission capabilities between the Nordic countries, the Nordic TSOs collaborate through multiple organizations, such as European TSO association ENTSO-E, Nordic imbalance settlement platform eSett, Nordic Regional Security Coordinator (RSC) and multiple other organizations. These forms of collaboration aim to ensure that the international transmission capabilities match with the societal energy transition ambitions.

Analysis of historical exchange data shows that there is a clear pattern of net electricity flows from the hydro-intensive Norway and Sweden towards Finland, Denmark and rest of the Northern Europe, especially during hours when *residual demand* is high. Residual demand means the share of power that needs to be generated after using available VRES resources to match the electricity demand and supply profiles. Residual demand is calculated each time period by reducing the available VRES generation from the total demand. Share of residual demand increases if the total demand increases without increase in VRES production; or the VRES production reduces faster than demand (Schill 2014).

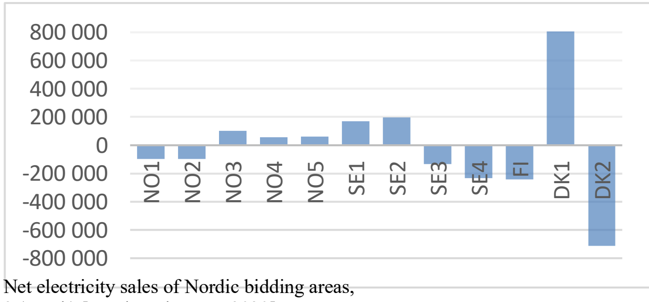

Figure 2. Net electricity sales of Nordic bidding areas, 2018-2019 (MWh) [Nord Pool Group 2020]

As shown in Figure 2, the annual net exporters within the Nordic electricity markets (excluding regional exports) are bidding areas SE1, SE2, NO3, NO4, NO5 & DK1. The net importers are bidding areas FI, SE3, SE4, NO1, NO2 and DK2[1]. The power exchanges between the European countries are important to balance intermittent RES feed-in and to ensure the maximum consumer and producer surplus in the market area. It can also be noted that the Scandinavian countries combined have a positive exchange balance (Maaz 2016). According to the set standards and recent research the current interconnection capacities are sufficient for the current generation and load mixes (Söder 2020).

2.1.1 Current boundaries of VRES utilization growth

With increased share of VRES utilization in the power system the importance of being able to maintain and operate dispatchable generators with quick ramping up and down potential becomes more important. The analysis of residual load is used to inspect the

[1] The abbreviations refer to electricity bidding areas SE1-4 in Sweden, NO1-5 in Norway, FI In Finland and DK1-2 in Denmark, as explained in Figure 1.

need of dispatchable generator usage at each stage of the power system. The share of VRES in the power system poses more requirements for the power infrastructure. The share of VRES in the power system dictates how much transmission, storage and power quality stabilizing infrastructure will be needed to keep the power system stabile. The phases and impacts of increasing share of VRES production are described in Table 1. As observed, the gradual shifting towards more VRES intensive energy system provides time to identify the development stage and topical technical challenges. Nordic Electricity Market area has abundant resources of flexible hydropower which makes the VRES integration easier than areas without hydropower capacity. Currently the development stage of the Nordic grid is in the Phase 3 of Table 1, where "flexibility becomes relevant with greater swings in the supply/demand". This means that the large increase of wind power production capacity starts to require attention from the grid and market operators. Local TSOs have in good time agreed demand flexibility contracts with large industrial consumers, refined the information systems to support the development of aggregated load adjustment, prepared curtailment strategies with compensation agreements and started to identify the next stages of grid and generation mix development. The rapid deployment of wind power capacity has not yet caused significant physical or market disturbances in the Nordic electricity system.

Table 1. Penetration Stages of Intermittent Electricity Sources in the Power System (Philibert 2017).

Phase	Description
1	VRE capacity is not relevant at the system-level
2	VRE capacity becomes noticeable to the system operator
3	Flexibility becomes relevant with greater swings in the supply/demand balance
4	Stability becomes relevant. VRE capacity covers nearly 100% demand at times
5	Structural surpluses emerge; electrification of other sectors become relevant
6	Bridging seasonal deficit periods and supplying non-electricity applications; seasonal storage and synthetic fuels

As observed from the National Energy and Climate Plans (NECP FI 2020), the future of Nordic generation-mix leans heavily towards the increase of wind power plants. One of the key concerns with high wind power generation levels are the availability of enough transmission interconnectors to balance the varying generation and load profiles between regions.

2.1.2 Energy Security of high VRES systems

Energy security is a multidimensional and evolving concept. Moreover, it is increasingly popular as a research subject. A large body of research concentrates on defining and measuring energy security, but no academic consensus has been reached in either composing a clear definition or an indicator that would be useful for political decision making. The latter is largely due to the lack of a money-metric translation between different dimensions of energy security (Beohringer and Bortolamedi 2015).

The recent research shows that even with the strong political agreement the Nordic power system may currently not be technically adequate yet to accommodate the most ambitious plans of variable electricity generation increases. Recent publication evaluates that the Finnish power system flexibility is limited and needs to be further developed to adequately accommodate wind power generation that exceeds 20% of the total electricity demand (Zakeri 2016). Other research results claim the existing hydro power reservoirs in Norway could regulate up to 90 TWh of annual wind power generation before the surplus generation starts to negatively affect the of the wind power installment capacity factors and system reliability (Hirvijoki 2020).

Curtailment is an alternative way of balancing the electricity flows in a high VRES penetration power system. Curtailment means controlled, involuntary and temporary scaling down of intermittent electricity generation. Market mechanisms make curtailment currently a non-desired event that occurs when VRES production needs to be shut down due to technical limitations in the distribution or transmission systems. During peak production hours when intermittent generation capacity production is at its highest the generation may exceed the total local demand. In these events the produced electricity needs to be transmitted to other locations with remaining residual demand. If the production levels are high and the required distance to transmit the electricity to supply ongoing demand is long, some lines in the transmission network may get congested – meaning that the technical limitations of the transmission capacity are reached. Uncontrolled congestion would cause voltage violations and thermal stress and potential damage to the network components, thus curtailment, rerouting of transmission patterns, demand response and energy storage are always the preferred solutions (Vargas 2014).

Need for curtailment may become necessary if the transmission grid development lags the VRES generation development. Problems may occur if the VRES production peak happens during low consumption hours, such as in the night-time, or when the intermittent production conditions increase so suddenly that the dispatchable generation capacity cannot scale down the production quickly enough to keep the system in balance, or when a major transmission capacity failure occurs. Variable costs of VRES is near zero, so curtailing VRES does not increase costs much, it mainly reduces the *capacity factor* of VRES production plants, leading to higher cost per produced MWh during the lifetime of the plant. This leads to reducing the return of investment (ROI) of the wind power generation projects. Thus, the need for curtailment reduces the profitability of wind power investments and the responsibility for carrying these costs vary in different electricity markets. In the Nordic electricity market, grid operators carry the management responsibility and cost of curtailment activities. When VRES represents a large amount of total system generation, storing all excessive production in electrical storages become economically challenging with the current development stage of the electricity storage solutions (Schill, 2014).

2.2 Available VRES Storage Solutions

The estimations about the ratio of VRES production and required energy storage capacity vary significantly. The research by Zerrahn et al. (2018) has screened the scale of storage requirements in various European energy scenarios. Sinn 2017 estimates 50% wind production to require 0,42% of annual electricity demand storage (2100 GWh in the case of Germany), while Schill and Zerrahn estimate for 68% wind power penetration to require 0,01% (55 GWh for Germany) of annual electricity demand as the required storage capacity. Pape et al 2014 estimates little to no need for storage capacity in Europe in the near future. Repenning et al 2015 estimate storage capacity equivalent to 0,02% – 0,03% (170 GWh) of annual European electricity demand to be sufficient for 83% – 91% VRES penetration in Europe. Scholz et al 2017 estimate storage capacity equivalent to 0,08% (440 GWh) of annual electricity demand in Europe to be sufficient stabilizer for 74% VRES penetration. Cebulla et al 2017 derive the European storage capacity need to be 1% (5000 GWh) of the annual electricity consumption in a transmission-constrained scenario and 0,5% (2500 GWh) in transmission-enabled scenario, both with 80% VRES penetration. German Federal Ministry for Economic Affairs and Energy 2017 estimate storage capacity of 0,01% (55 GWh) of annual demand be sufficient for a Pan-European renewable share of 65%”

Opposing views such as Sinn 2017 suggests technical limitations to electrical storage potential. In a modeling scenario of Germany, he illustrates that in a 100% VRES scenario 61% of the generated electricity would go to waste. With “no wasted electricity” electrical storage limitations would only allow 30% of German electricity demand could be filled with VRES. Also results from EU funded research project eStorage 2015 suggests that European potential to pumped-hydro storage would not even cover the needs of 100% VRES system in Germany alone. Zerrahn et al 2018 criticize these extreme approaches that only take into consideration scenarios where all or none of VRES generation is stored, suggesting that a partial-storage partial-curtailment strategy would be the most cost-efficient. Due to the diverse range of approaches to this complex problem, estimations for electricity storage requirements in a +50% VRES penetration scenario vary between 0,01% to 1% of annual electricity demand with variability of two orders of magnitude, as shown in the research compilation in Table 2.

Table 2. Compilation of high VRES storage model scenario results (Zerrahn et al 2018)

Study	VRES Penetration %	Storage % of annual demand	Storage in GWh	Notes
Sinn 2017	100	0	0	German system. 61% curtailment
Sinn 2017	50	0,42	2100	German system. No curtailment
Schill and Zerrahn 2018	68	0,01	55	German system. Curtailment
Pape et al 2014	45 – 69	0	0	Increased transmission, CHP source of flexibility
Repenningen et al 2015	83-91	0,02 – 0,03	170	
Scholz et al 2017	74	0,08	440	
Cebulla et al 2017	80	0,5 – 1	2500 – 5000	Higher estimate with transmission-constrains
German Federal Ministry for Economic Affairs and Energy 2017	65	0,01	55	Pan-European scenario

Using the estimations above the range of electricity storage needs for the Nordic Electricity System can be calculated. Total electricity consumption in the Nordic Electricity System in 2030 is projected to be in total 417 TWh. Assuming the required storage range between 0,01% (0,417 TWh) and 1% (4,17 TWh) of the total annual electricity demand, Norwegian hydropower with 84 TWh storage capacity could easily balance a high VRES penetration system in the Nordic electricity area while having plenty of surplus to serve the Southern European countries. Hydropower is suitable for seasonal storage, which is important with the highly varying seasonal demand (Dunn et al 2011).

As presented in Figure 3, GWh to TWh scale solutions are rather limited to large scale mechanical storage methods, such as Pumped Hydropower Storage (PHS) and Compressed Air Energy Storage (CAES) or chemical energy storage such as different types of batteries, flow batteries or combination of electrolysers and fuel cells.

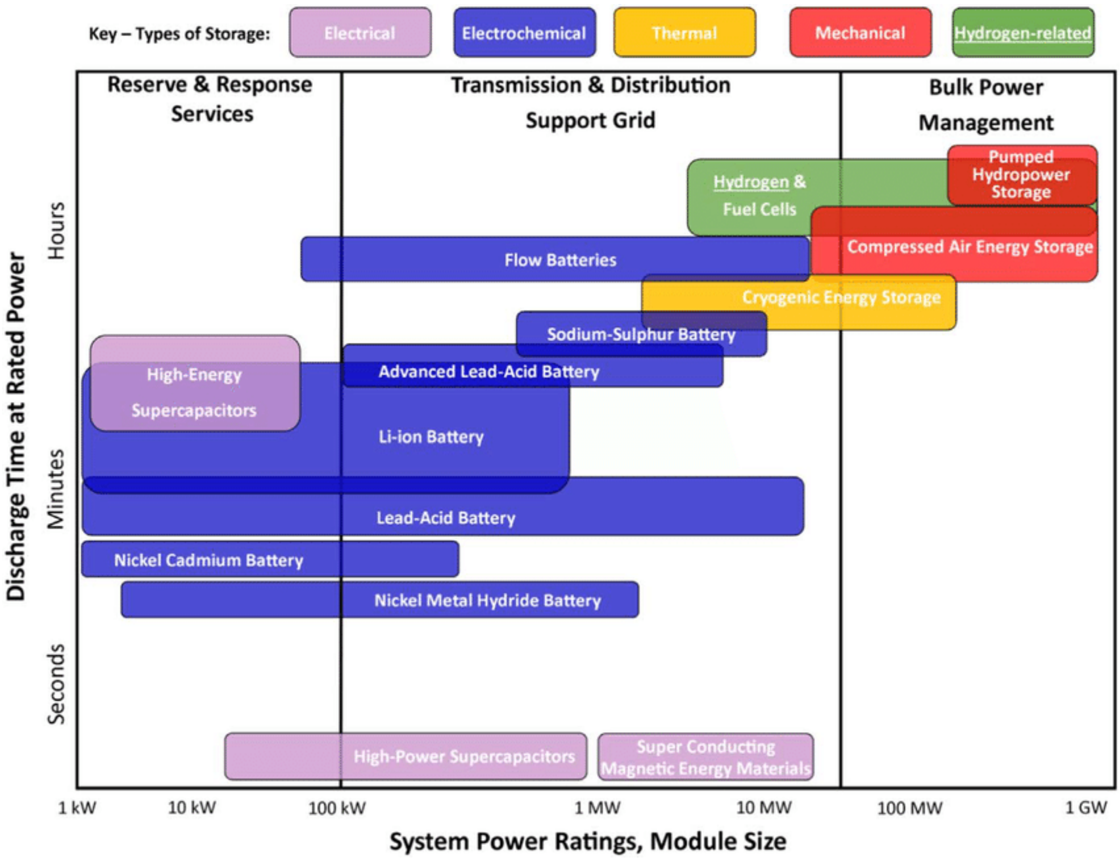

Figure 3. Comparison of energy storage technologies, Møller et al 2017

Hydropower's potential as a VRES balancer was chosen as the research topic of this thesis, due to the availability, seasonal suitability and affordable capital costs per kW and per kWh of the mature hydropower technology in the Nordic electricity markets.

After a brief policy and planning review revealed that there is very little strategic or political will to increase the hydropower water reservoir volume in the Nordic electricity market area. Hydropower capacity is slowly declining in Sweden (Karlberg 2015) and Finland (Motiva 2021), Norway had estimated annual 2,3 TWh hydropower generation capacity under construction in the beginning of 2021 (Energia Fakt Norge 2021).

While providing the majority of Nordic electricity, hydropower also affects the fish migration and water ecosystems broadly. Pumping can increase the water temperature and stir solids into the water from the bottom sediments compromising water quality. Pumping may also cause water flows that prevent ice covers from forming, causing impacts to the natural habitats of wildlife. The risk of a reservoir breakage is a valid concern that has to be prevented with cautious preparations (Yang 2016). These are the most common arguments used to object the construction of new hydropower projects.

For the reasons mentioned above, few new projects for new hydro reservoirs in the Nordic countries have been initiated. The Swedish multiparty agreement in 2016 decided that all hydropower plants should have modern environmental permits within 20 years (Swedish Parliament 2016). Due to the social resistance towards increasing Nordic hydropower reservoir volume, the only way to leverage more energy storage and high VRES system balancing opportunities out of the already tapped water-way resources is to increase the generation turbine, tunneling and upstream-pumping efficiency and capacity between the existing reservoirs; and to increase the transmission capacity from the hydropower sites to the urban and industrial areas to further optimize the use of hydropower stations.

While transmission lines are generally well accepted in the society, the increase in the transmission capacity also faces constraints and opposition due to the competitive plans in land use. Changes in landscape and impacts on nature are also general public concerns related to transmission capacity increasing projects (Fingrid 2020).

2.3 Nordic Hydro Power as a Balancing Component for Wind Power

Hydropower can be divided into three main categories: reservoir storage, run-of-the-river and pumped storage hydropower (PHS). This study focuses on the PHS systems due to the before mentioned limitations in reservoir and new site capacity development potential. Pumped storage hydropower uses the potential energy in water to produce electricity in *turbine mode*. In *pump mode*, electricity is used to pump water to a higher elevation to store energy as potential energy in water. PHS are characterized by long lifetime expectancy, typically between 50 and 100 years, a round-trip efficiency of 70–85% and a fast response time, usually in the order of seconds or minutes (Harby et al 2013). The variances in the annual reservoir volumes can be potentially balanced over the year by higher capacity and usage rate of PHS stations.

The design of pumped storage hydropower is based on more starts and stops including change of energy direction and alternating electricity production, than conventional hydropower plants. Therefore, it is very important to ensure the safety of the whole dynamic system, including water ways, turbines, pumps, generators and transmission lines (IEA 2020). Modernizing the existing hydro turbine fleet and increasing the number and capacity of pumped hydro power stations may provide significant utilization increases for the existing water reservoirs (Charmasson 2016).

Research results of the Joint Research Center (JRC) of EU were used to evaluate the potential development sites for new PHS projects in the Nordic electricity market. In European context Norway has the most non-utilized realizable PHS potential in all of the JRC PHS study scenarios. By using the 20 km range topological differences between upper and lower water reservoirs, the potential of annual PHS energy storage capacities are 27,7 TWh in Norway, 5,5 TWh in Sweden and 0 TWh in Finland (JRC 2013). This study focuses on the PHS increase potential in Norway

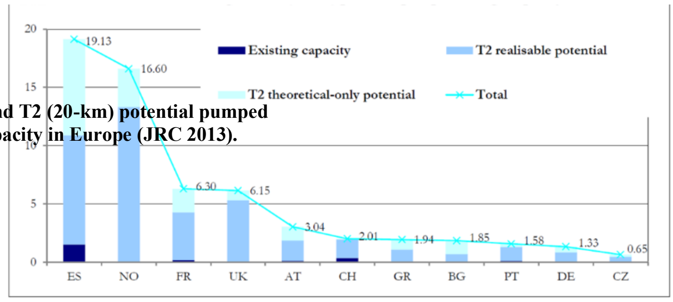

Figure 4 – Existing and T2 (20-km) potential pumped hydro storage capacity in Europe (JRC 2013).

due to the high availability and extensive research available of the development potential. Since typical PHS facilities have a hydraulic head of 200 – 300 meters with reservoir volumes of the order of $10x10^6$ m^3 (Yang 2016), only sites with sufficient energy potential were considered in the scenario modeling.

Over half of European Pumped Hydro Storage (PHS) potential is within Nordic energy markets, especially in Norway. Estimations about the round-trip-efficiency of PHS ranges between 70 % (Deane et al 2010) to up to 80% (Yang 2016 p.25). Hydropower provided significant share of electricity in 2018 in Norway in total 141 TWh/a representing 94,3% of Norwegian production and 50% of Europe's water reservoir capacity, in the period 1990–2015 (Energiefakt Norge 2019). According to the Norwegian Water Resources and Energy Directorate, the annual natural inflow to Norwegian hydropower plants (NVE 2019) has varied by about 65 TWh making production predictions challenging. Due to lack of feasible business plans suitable for the evolving electricity markets, so far PHS is currently contributing only 0,16 TWh of stored energy (NVE-VK 2019).

Hirvijoki 2020 suggests that 120 TWh of annual hydro-generated electricity complemented with 90 TWh of annual wind power production could supply 100% VRES electricity of 210 TWh total demand of the Nordic Electricity Market – though this model does not consider the Nordic annual electricity consumption to reach 417 TWh by 2030 as in this model. Peak production capacity for Norwegian hydropower is 33 GW and for Swedish hydropower 16 GW. Charmasson et al 2018 claim that the Norwegian PHS potential could be developed further up to 19 GW in capacity. Graabak et al. 2017 claim that the need for West-Central Europe energy storage with high VRES generation ratio in 2050 will grow to 23 TWh/month and hourly balancing need up to 300 GW/h. Cedren researchers seem to believe that the current Norwegian hydro reservoir capacity with increased generation, pumping and transmission capacity would be sufficient to satisfy the energy storage needs of a market area broader than the Nordic electricity market.

Technically PHS systems can respond within seconds and are able to reach their full production capacity within minutes. This rather fast response time allows PHS units to participate into multiple markets as listed in Table 3. The Nordic electricity market has currently operational markets for electricity options, futures, day-ahead settling, SPOT trading; and FCR, FCR-D, FFR, aFRR, mFRR, regulating, balancing and settling services. These marketplaces are operated by different organizations and different market rules according to their specified legislative frameworks and power system requirements.

Many of the available markets are rather new and the operational profitability considering the wear and tear of the turbine equipment have not yet been optimized enough to incentivize full integration of PHS producers into all available markets.

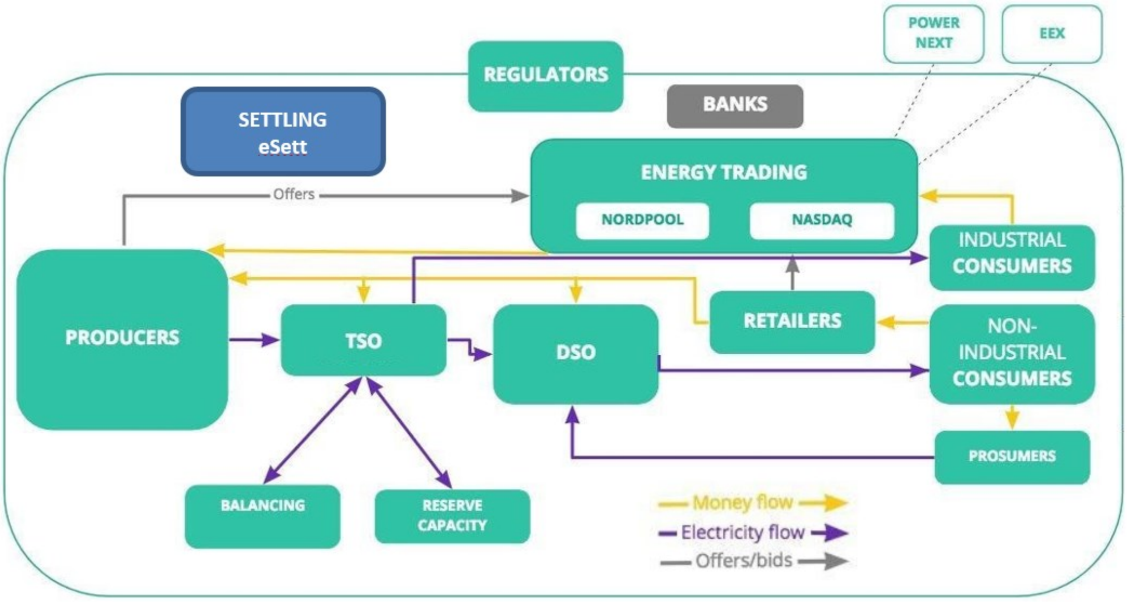

Figure 5. Simplified illustration of the Nordic Electricity Market in 2020

Table 3. PHS services for different marketplaces in the current market structure

#	Service	Marketplace
1	Regulation reserve	Regulating markets
2	Flexibility reserve	TSO procurements (reserves)
3	Contingency Spinning Reserve	TSO procurements (FCR-markets)
4	Contingency Non-Spinning Reserve	TSO procurements (FCR-markets)
5	Replacement / Supplemental Reserve	TSO procurements (reserves)
6	Load following	Balancing and regulating markets
7	Load Leveling & Energy Arbitrage	Balancing markets
8	Integration of Variable Energy Resources	TSO procurements (demand response)
9	Generation Capacity	All markets except aFRR
10	Reduced thermal unit cycling / Reduced Environmental Emissions	Guarantees of Origin / Green Certificate markets
11	Reduced transmission congestion	TSO procurements
12	Transmission deferral	TSO procurements

High flexibility of PHS capacity could potentially respond to many of the technical concerns that high VRES penetration scenarios pose to the current structure of Nordic power system. These mechanisms are further investigated in Chapter 2.4.

The hydropower industry is challenged to further develop its earlier operational optimization tools to include all operational variables and multiple markets simultaneously. Hydropower operators face the decision whether to use the water in the hydro reservoirs now or later. Therefore, the relevant costs are the opportunity costs (water value) of using the water in the future (Sandsmark, 2010). The water value is hence influenced by hours with thermal price-setting technologies with higher variable costs. This can happen directly or indirectly, if a price-setting hydro reservoir provides a relevant opportunity for other reservoirs. The opportunity costs are mainly determined by the possibility to save the water and use it in the hours with higher electricity prices. If the reservoir is sufficiently sized for the inflows, the pattern of inflow over the year is not important, only the overall energy input. The smaller the reservoir in relation to the turbine capacity, i.e. the smaller the load factor, the more the marginal water value increases. Hydropower plants in the Nordic electricity market then reach operating hours where typically prices are not set by mid-merit plants but rather by peaking plants (Jahns et al 2019).

Figure 5 shows the annual variance in the water reservoir levels in NO, SE & FI. What can be noted is that the highest consumption of the reservoirs occurs during the winter months. This is logical, since the hydro reservoirs have the capacity to store a lot of energy and sell it during the highest demand hours. Since the highest electricity price hours are statistically much more likely to occur abundantly during the winter months, the hydro power plants aim to maximize their production during the high electricity price season. Time-varying equilibrium filling level is reflective of average water inflow and electricity demand patterns. Therefore, the deviation from the equilibrium filling level is a clear indicator of scarcity or abundance and should influence the water value (Jahns 2019).

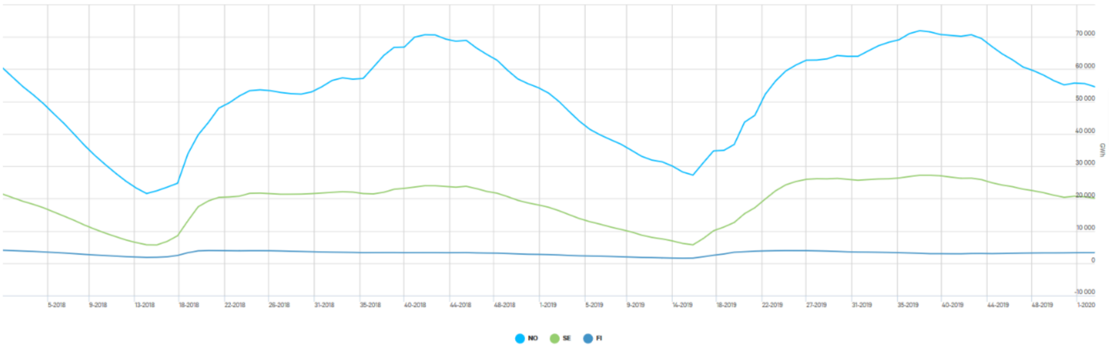

Figure 6. Nordic Hydro Reservoir 2018-2019, GWh (NordPool 2020)

2.4 Economics of Pumped Hydro Storage

Optimal storage investment sizes and locations depend on competition (market power) and the existing generation profiles (Virasjoki 2020). A cost-benefit analysis of a total 60 GW hydropower capacity in Norway (of which 13.7 GW pumped-storage) and a corresponding transmission capacity to Europe was carried out in HydroBalance research project in Norway (Moser et al. 2016).

The total investment costs in $/kW & $/kWh of the Norwegian PHS development sites vary according to the local limitations in watercourses, reservoir volumes, flexibility in water volume management and distance from the transmission networks and substations (Hydrobalance 2018).

The hydropower optimization modeling results of (Birkedal 2016) show that both the hydro balance, temperature inflow, short-run marginal-costs (SRMC) of coal and gas power generation and power prices significantly affect the profitability of short-run hydro operations.

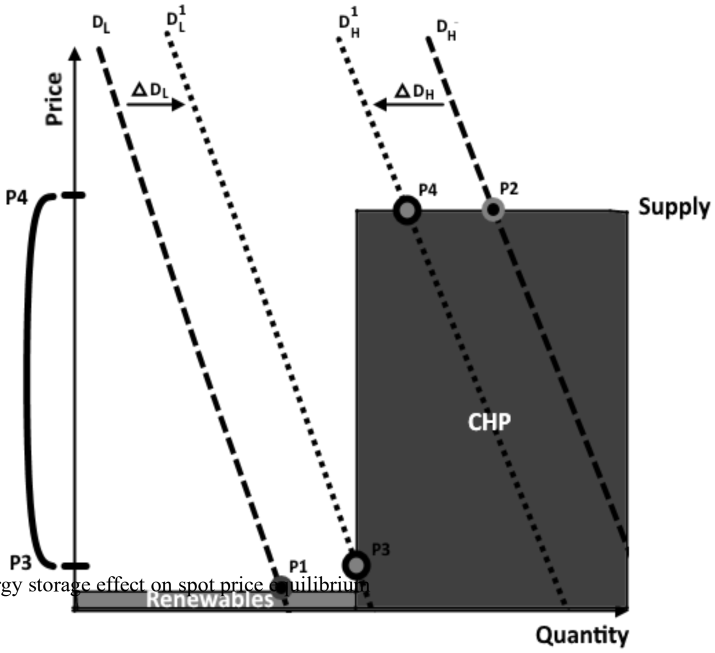

Figure 7. Energy storage effect on spot price equilibrium

The increase in PHS capacity should in theory affect the supply-demand equilibrium price of electricity auctioned with SPOT-prices. The Figure 7. Energy storage effect on spot price equilibrium illustrates the theoretical rationale for these effects in electricity auction prices. DL represents the quantity of electricity demand during a low demand period of the observed time scale. DH represents the peak demand of the same observed time period. The arbitrage chance for PHS facilities emerges from this spot price difference. In theory when a storage operator increases the energy demand during the low demand and low-price hours, the demand curve DL1 shifts to the right. During the high demand high price hours, PHS facility can be considered to lower the demand curve by acting as an increased low margin cost supply. The arbitrage benefit left for the energy storage operator is the difference between the new price settling points P3 and P4. Even though this does not exactly represent in detail all the interactions in the market, the basic principle works well in analyzing energy storage market dynamics.

Since Nordic electricity system already has significant capacity of dispatchable hydropower to balance the electricity SPOT-price fluctuation, the profits that can be gained from additional PHS facilities in the Nordic electricity markets are limited. The market situation in the Nordic electricity markets may change if combustion-based dispatchable generation or baseload-generation is reduced significantly, if industrial development or increase in the interconnector capacity increases the demand of Nordic electricity generation and storage, or if new energy storage technologies become highly competitive in the markets. Further EU's Energy Union goals to integrate the Nordic electricity market with the other European electricity markets seems to put development pressure towards these directions (EC 2014).

By storing energy, PHS pumps can be used as flexible load to reduce the need for curtailment and the generation turbine coupled with the stored energy can be used to avoid outages. Coupled with advanced power electronics, PHS can also reduce the harmonic distortions and eliminate voltage sags and surges. Variable-speed PHS can provide frequency regulation services both in pumping and generation mode. If the competitive marketplaces exist for auctioning services in these markets and the market prices in these auctions are frequently high enough, PHS units may be a competitive solution to provide some of these services in the electricity markets (IRENA 2020).

The highest business risks in PHS management have to do with the cost-development of closest competitive technologies, gas turbines and electrical battery storages; ability to reach the optimal market performance; and the oversupply-risk that occurs in some hydro-dominated systems such as the Nordic electricity market. Uncontrollable seasonal inflows, stream-flows and wind conditions with the environmental permits of PHS plants may lead to complex oversupply conditions that may require new type of operational optimization methods (Su et al 2017). During a combination of unfavorable market conditions including high pumping price, low load factor and low electricity price volatility the pumped hydro generation becomes more expensive than gas power (CEDREN 2016). The price of natural gas and novel battery technologies are key factors regarding PHS market competitiveness. Since PHS is essentially a peak load technology it competes directly with the natural-gas-powered generators. The flexibility of PHS nevertheless makes it useful in multiple markets.

The closest benchmark to PHS capacity increases are the investment projects in natural gas turbines – and during the 2020's some of the electrical battery technologies will develop to be competitive in at least some of the markets PHS operates in. In a case study in Norway the PHS simulation results showed that participating in all 6 different types of electricity marketplaces would increase the total income of the plant by 22% and increase the profitability of the facility by a factor of 6 (Hydrobalance 2018). Market research (Wolfgang 2015) claim that PHS investments have negative profits with historical prices and one-market strategy. Nevertheless, models with multi-market strategy together with electricity price volatility assumptions for the future suggest that the income from PHS investments may increase by 21%.

In the economic analysis of PHS systems additional research is required to fully understand the methods of holistic quantification of the cost of frequency control in high VRES energy systems. The broader list of services PHS facilities can provide to different markets is presented in Table 3 providing brighter prospects for PHS capacity increase investments (Yang 2018). As a low-emission energy source PHS gains competitive advantage over gas turbines in the power markets with the rising emission trade permit costs. Literature review shows that the emission permit price per ton forecasts for 2030 range between 0 € – 100 €/ton$_{CO_2}$; from 0 – 30 €/ton$_{CO_2}$ (IMF 2019), 35 €/ton$_{CO_2}$ (EC 2016), 50 €/ton$_{CO_2}$ (Schjolset 2014), 74 €/ton$_{CO_2}$ (Garanti 2018) & 50 – 100 €/ton$_{CO_2}$ (CPLC 2017). The production cost impacts of emission permit price development should be further studied to identify the potential threshold prices that dictate the price competitiveness of PHS generation.

3 Materials and Methods

3.1 EnerAllt –model

The projected scenarios are modeled based on the Nordic Energy Market model "*EnerAllt*" developed at the Aalto University in Finland. EnerAllt is a linear optimization modeling tool for the Nordic electricity and regional district heat markets. Modeling logic operates by simulating the decisions made by electricity suppliers according to the SPOT-prices of the electricity market. The market is modeled on an hourly-basis and in bidding area resolution. The price-independent demand profiles and the availability of low VOM cost generation limit the quantity of profitable operational hours for combustion plants. The transmission capacities are limited by the sizing of modeled interconnectors. The common system price gets determinate by the market equilibrium according to the purchase and sales bids of all market participants. The system price neglects the limitations created by the transmission restrictions. The price differences between the bidding areas are created through the congestion in the transmission lines. The demand of both electricity and heat is considered inelastic.

In this study, a MATLAB-based linear programming model Enerallt is used to model the Nordic electricity market with an hourly step resolution. The objective function (1) is to minimize the short-term operation costs in the power sector and in the district heating sector, if included.

$$\min_{p_{ij,t},p_{ijk,t},h_{ijk,t}} \left(\sum_i \sum_j \sum_t c_{ij,t}p_{ij,t} + \sum_i \sum_j \sum_{k\neq j} \sum_t c_{ij,t}p_{ijk,t} + \sum_i \sum_j \sum_n \sum_t c_{ij,t}h_{ijn,t}\right) \quad (1)$$

In (1) $p_{ij,t}$ represents the power supply of technology i in bidding area j, $p_{ijk,t}$ is the power supply of technology i in bidding area j that is exported to bidding area k and $c_{ij,t}$ is short-term marginal cost of production for technology i in bidding area j. Moreover, in (1) $h_{ijn,t}$ represents the heat supply of technology i in bidding area j in district heating network n and $c_{ij,t,}$ is the short-term marginal cost of heat conversion of technology i in bidding area j. In (1) t is the hour index.

A more detailed description and mathematical formulation of the model is presented in (Farsaei 2020), (Khosravi 2020) In this study, the model is modified so that the state of each decision variable is determined utilizing a rolling interval procedure. In this regard, the production planning problem is divided into partially overlapping subintervals T (168 hours). After the optimization of subinterval T, the time interval is shifted forwards by 24 hours. The initial conditions from the previous subinterval are fixed to reflect the state reached by the plan up until the beginning of the new subinterval. Furthermore, the state of time dependent variables is updated accordingly, e.g. as presented in (2) in regard to hydropower reservoir.

$$V_{j,t} = V_{j,t-1} + Q_{in_j,t} + Q_{c_j,t} - Q_{d_j,t} - W_{j,t} \qquad (2)$$

In (2), $V_{j,t}$ is reservoir level, $Q_{in_j,t}$ is reservoir inflow, $Q_{c_j,t}$ is water pumped to reservoir, $Q_{d_j,t}$ is water discharge and $W_{j,t}$ is spilling.

Based on the demand curves and the availability of generation capacity with a large range of production costs, the model optimizes the conditions on the markets determining the market outcome; thus the bidding area prices, electricity exchange flows between bidding areas, carbon emissions of production and the ratio of used generation technologies for each hour. The optimization is done for sliding 7-day timeframes and the solution is calculated separately for each hour of a year.

The Nordic power system is described as an 18-node system, where the nodes represent individual bidding zones in the Nordic electricity market. Electricity generation mix of Finland (FI), Sweden (SE-1, SE-2, SE-3 and SE-4) and Norway (NO-1, NO-2, NO-3, NO-4 and NO-5) are modeled as generation technology-specific bidding zones. The generation mix in these bidding zones is based on the generation capacity data from 2016 (ENTSO-E 2019, Finnish Energy 2019, Swedish Energy Agency 2018), with the changes listed in Table 5Table 4.

The remaining bidding zones are treated as external regions. Power plants in each external region are aggregated into one production unit, which short-term marginal cost of production is the hourly electricity spot price in that bidding zone. Generation from combined heat and power (CHP) units is considered to depend solely on the competitiveness in the electricity market. Technology cost data included in the short-term marginal operation cost is based on the cost estimates in (Danish Energy Agency, 2015). Fuel costs include: fuel price (OSF 2016), (Swedish Energy Agency 2016), fuel taxes (Swedish Energy Agency 2016, SVT 2016) and emission costs. The assumed average emission price is 27 €/tCO_2 (McGowan 2018).

3.2 *Data Sources & Modeled Scenarios*

This section compiles the sources used as the simulation input data.

Table 4. Simulation Data Sources

Dataset	Source	Values
Basic Model Structure	2016 supply quantity and profile with the following exceptions: Wind generation profiles (described below) Shutdown of Ringhals I & II (nuclear) Starting of OL3 (nuclear)	SE2: -881 MW (BWR) -900 MW (PWR) FI: +1600 MW (EPR)
Forecasted electricity Demand 2030	Danish Energy Agency - *Basisfremskrivning 2017* (Basic Projection 2017). 2017. Norwegian Ministry of Petroleum and Energy - *Kraft til Endring–Energipolitikken mot 2030 (Power for Change –Energy Policy Towards 2030*). 2016. Swedish Energy Agency - *Scenarier över Sveriges Energisystem 2016 (Scenarios of the Energy System of Sweden 2016*). 2017. Finnish Ministry of Economic Affairs and Employment - *National Energy and Climate strategy for* 2030 (2016) For the rest of the bidding areas: EU Reference Cases 2016	FI: 92 TWh SE: 138 TWh NO: 143 TWh DK: 44 TWh Total Nordic: 417 TWh
Forecasted fuel prices	ENTSO-E TYNDP 2018 – EUCO2030 Scenario Data	-
Stock of technologies	Dispatchable: Condensing Hard Coal, Condensing Peat, Condensing Heavy Fuel Oil, Condensing Municipal Waste, Condensing Biomass, Gas Turbine, Carnot Cycle Gas Turbine, Combined Hard Coal, Combined Natural Gas, Combined Biomass, Combined Municipal Waste, Combined Fuel Oil, Combined Biogas Non-dispatchables: On-shore wind, photovoltaic (PV), Boiling Water Reactor (BWR) pressurized water boiler (PWR), European Pressurized Water Reactor (EPR), solar thermal	-
Interconnector Capacity in 2030	ENTSO-E TYNDP 2018 Project List	nTc FI-RU = 0 & nTc RU-FI = 0 import same as 2016
Forecasted Electricity Prices 2030	SE: Fingrid – Nordic Grid Development Plan (2019) NO: Fingrid – Nordic Grid Development Plan (2019) FI: Fingrid – Nordic Grid Development Plan (2019) DK, EE, LT, DE, GB: TYNDP Scenario Report EUCO 2030	SE avg/a: 50 €/MWh NO avg/a: 46 €/MWh FI avg/a: 51 €/MWh DK, EE, LT, DE, GB avg/a: 67€/MWh
Wind production profiles	Wind park simulations made with www.renewables.ninja software and 2014 wind data. 5 identically sized wind parks were modeled in each bidding zone. Locations of the parks were chosen according to the current wind turbine installations and high wind capacity factor.	Production profile for 8782 hours, production varying from 2-90% of installed capacity
High Wind Scenario	FI, SE, NO: Wind Europe – Wind Energy in Europe scenarios for 2030, High Scenario (2017) DK: TYNDP 2018 / EUCO 2030 SE: (WWE 2030, High) Bidding Area ratios of added capacity distributed according to the 2016 ratio	FI: 10 000 MW SE: 13 000 MW NO: 11000 MW DK: 8140 MW Total: 42100 MW
Low Wind Scenario	ENTSO-E TYNDP EUCO 2030 FI: WWE 2030, Low SE: WWE 2030, Low NO: WWE 2030, High DK: WWE 2030, Low Bidding Area ratios of added capacity distributed according to 2016 ratio	FI: 4140 MW SE: 9000 MW NO: 4000 MW DK: 6500 MW Total: 23640 MW
Planned PHS projects	Addition in PHS capacity in Norway taken from Charmasson 2016, Harby 2013 Belsnes 2018. NO2: 3500 MW NO5: 6500 MW	3,5 GW of PSH capacity added to NO2 6,5 GW of PHS capacity added to NO5
Emission Permit Price	TYNDP EUCO 2030 –scenario report	27 €/ton$_{CO2}$

Scenario 1: Low Wind
In the Low Wind -scenario the development of wind power generation capacity in the Nordic electricity market is rather modest by the year 2030. The total growth of wind production capacity increases in the market area by 18% from the 2019 level. The wind power capacity increases are distributed to the bidding areas per nation according to the current installed capacity ratios of the total production capacity. This scenario aims to model the potential impacts of a slowly transitioning Nordic electricity system. This scenario works as a reference case to compare the impacts of further increases in the renewable energy generation investments in the Nordic market area.

Scenario 2: Low Wind + PHS
In the Low Wind + PHS –scenario, conservative increase of wind power production capacities is applied in the same way as in scenario 2. In total 10 GW of new PHS capacity is also added to the bidding zones NO-2 & NO-5. This represents an increase of 635 % in the total Nordic PHS capacity. The added capacity for the areas is reasoned with the research results of Hydrobalance, a decade-lasting Norwegian research project that mapped the hydro power capacity increase potential in Norway. This scenario aims to model the impacts of the suggested installed PHS capacity in the Low Wind -reference scenario.

Scenario 3: High Wind
The High Wind -scenario assumes a more ambitious increase in the installed capacity of wind power generation in the Nordic electricity market by the year 2030. In this scenario the total capacity growth in the Nordic electricity market by 2030 compared to the 2019 level is 110 %. This scenario models the impacts of large-scale wind power generation investments and installations for the Nordic power system.

Scenario 4: High Wind + PHS
The High Wind + PHS –scenario includes the wind power generation capacity increases from the 2016 level according to the High Wind –scenario. The same PHS capacity of 10 GW, an increase of 635 % from the 2016 level, is added to the bidding zones in NO-2 an NO-5 as in Low Wind + PHS –scenario, to model the potential execution of the most potential PHS capacity increase. This scenario models the impacts that installations of the suggested PHS capacity would have combined with the high availability of wind power capacity.

Wind Power Capacity Placement and Generation Modeling

To distribute the national capacity increases among different bidding areas, two approaches were considered. First option was to scale up the national wind power production and distribute it to bidding areas according to the currently installed capacity ratios per bidding area. Another option was to analyze the amount of capacity permits applied for new wind turbines in each bidding area.

The first approach was chosen for every country except Norway due to the inconsistency of permit application data and uncertainty of the application outcomes. By dividing the national wind power increases from Wind Europe's *Wind Energy in Europe: Scenarios for 2030* (2017) for each bidding area according to the current distribution of wind generation capacity, the following Table 6-8 were summarized. The capacity in Norway is added in the ratio of new wind park applications, since the new developments divert significantly from the current ratio of wind power generation.

The production profiles for each bidding area capacity was built with Renewable.Ninja -software, which is an online modeling tool for wind power plant generation profiles. The forecasted production was distributed among the bidding areas mainly to locations with significant new capacity permit applications currently being processed. 5 wind power plants were modeled for each bidding area with the total given capacity to get a more accurate wind power production profile for each area.

Table 5. Modifications to scenario data.

Abr.	Scenario	Technology Portfolio (MW)			
			FI	SE	NO
	Reference year 2016	CHP, industry	5900	1430	0
		CHP, DH	3470	3740	1740
		Other thermal	2230	2580	380
		Nuclear Power	2790	9140	0
		Wind Power	1750	6400	1050
		Solar Power	0	103	0
		Hydropower	3110	16900	30200
		PHS	0	430	1440
S0	Common changes for 2030 scenarios	SE3: - 881 MW BWR SE3: - 900 MW PWR FI: Hard Coal replaced with Wood Chips FI: + 1600 MW EPR			
S1	Low Wind 2030	FI: + 1940 MW Wind SE: + 2500 MW Wind NO: + 2800 MW Wind DK: + 2000 MW Wind			
S2	Low Wind + PHS 2030	As S1, and NO2: + 3500 MW PHS NO5: + 6500 MW PHS			
S3	High Wind 2030	FI: + 7800 MW Wind SE: + 6500 MW Wind NO: + 9800 MW Wind DK: + 3500 MW Wind			
S4	High Wind + PHS 2030	As S3, and NO2: + 3500 MW PHS NO5: + 6500 MW PHS			

Table 6. Sweden Wind Power (WP) Development 2030.

	MW	TWh/a	% of national WP
SE-1 2016 Production	517	1,26	8,1 %
SE-1 2030 Low Forecast	920	2,42	8,1 %
SE-1 2030 High Forecast	1053	2,77	8,1 %
SE-2 2016 Production	2300	4,93	35,8 %
SE-2 2030 Low Forecast	3120	8,22	35,8 %
SE-2 2030 High Forecast	4654	12,26	35,8 %
SE-3 2016 Production	2000	5,56	31,2 %
SE-3 2030 Low Forecast	2740	7,22	31,2 %
SE-3 2030 High Forecast	4056	10,69	31,2 %
SE-4 2016 Production	1600	3,84	24,9 %
SE-4 2030 Low Forecast	2220	5,85	24,9 %
SE-4 2030 High Forecast	3237	8,53	24,9 %

The share of increased wind power capacity in Sweden is distributed according to the current production structure between the bidding areas. The new capacity is added based on the existing capacity by calculating the current share of national wind production in each bidding area and adding the same share of installed capacity into the bidding area. The current average capacity factor of 30% (WWE 2017) is used to calculate energy production

Table 7. Norway Wind Power (WP) Development 2030.

	MW	TWh/a	% of national WP
NO-1 2016 Production	0	0	0 %
NO-1 2030 Low Forecast	135	0,2	3 %
NO-1 2030 High Forecast	330	0,9	3 %
NO-2 2016 Production	313	0,74	3 %
NO-2 2030 Low Forecast	1220	3,9	19 %
NO-2 2030 High Forecast	3243	10,4	29 %
NO-3 2016 Production	388	0,78	37 %
NO-3 2030 Low Forecast	1405	4,0	37 %
NO-3 2030 High Forecast	3818	10,8	56 %
NO-4 2016 Production	342	0,59	32 %
NO-4 2030 Low Forecast	1275	4,5	32 %
NO-4 2030 High Forecast	3442	12,1	20 %
NO-5 2016 Production	19	0,01	2 %
NO-5 2030 Low Forecast	100	0,3	2 %
NO-5 2030 High Forecast	190	0,6	2 %

Forecast calculated by listing all applied and in-progress wind farm applications from NVE MAP ATLAS (excluding <10MW sites) and looking at the shares of development projects in each bidding area. The capacity increase per bidding area is calculated by taking the “High” scenario from Wind Energy in Europe: Scenarios for 2030, of 11000 MW cumulated capacity by 2030 and allocating the shares of production in bidding areas according to the shares of new project applications. Energy production is calculated by using the average capacity factor for Norwegian wind farms 33% (WWE 2017).

Table 8. Finland Wind Power Development 2030.

	MW	TWh/a
2016 Production	1753	2,86
2030 Low Forecast	4140	12,7
2030 High Forecast	11450	30,4

With an average capacity factor of 30%, this would mean around 11450 MW of total wind power production capacity. This would mean 650% increase in the wind power capacity from the 1750 MW level of 2016. The Finnish Wind Power Association has listed all the planned wind power projects in Finland and the list of screened sites and farm sizes totals to 16500 MW (FPWA 2019).

3.2.1 PHS Capacity Development

By 950 MW new PHS capacity and 14100 MW increase in transmission capacity give the highest socio-economic surplus (Henden 2016). Norwegian 2030 hydro pump storage scenario (Charmasson 2016) claims that results from case studies on large-scale energy storage and balancing services from Norwegian hydropower to Europe show technical potential to develop 20 000 MW of new hydro of which about 10 000 MW includes pumping. This would also require updates on the transmission network (Harby 2013). Most suitable PHS and turbine capacity development locations are found within the bidding areas of Norway and Sweden, mainly in the bidding zones NO-2, NO-5 and SE-1.

The existing hydropower facilities that could be upgraded with PHS capacity, meet the reservoir sizing requirements, comply with the head horizontal distance limitations, theoretical environmental permit limitations and are positioned favorably in relation to the Norwegian transmission network are presented in the Table 9. The investments into hydropower site capacity development would require new investments to new tunneling and high-voltage transmission lines (Solvang 2012).

Table 9. Recommended PHS development sites in Norway, based on Charmasson 2016 & NVE 2020.

Location	nTc	Capacity GW
Tyin (NO-5)	Shetland	3,74
Aurland 1, Aurland 2-3-5, Aurland 4, (NO-5)	Shetland	1,29
Sima, Lang-Sima (NO-5)	Scotland	1,12
Hol 1 Votna & Urunda, , Hol 2, Hol 3 (NO-5)	SE-3	0,36
Nore 1, Nore 2 (NO-5)	SE-3	0,26
Tinnsjö Mål etc. (NO-5)	SE-3	0,69
Mauranger/Oksla/Tysso 1 & Tysso 2 (NO-2)	Scotland	0,46
Kvilldal & Saurdal(NO-2)	GB	1,24
Holen 1-2, Holen 3 (NO-2)	GB	0,39
Jösenfjorden Saurdal (NO-2)	GB	0,64
Lysebotn 1, Lysebotn 2 (NO-2)	GB	0,37
Tonstad (NO-2)	NL	0,96

4 Results & Analysis

The scenario modeling results are compiled in the following Table 10 - Table **13**. The analyzed data in this study were the maximum capacity of import and export interconnectors *ImportMax (MW)* & *ExportMax (MW)*, the average usage rate of the interconnector capacities *ImportAvg (MW)* & *ExportAvg (MW)*, the share of time per annum the maximum interconnector capacity is at use (*Max Cap time (%)*). *Max Line Stress* indicates the annual peak demand for the line capacity. The price analysis consists of *System Price, Average Area Price*, standard deviation analysis *STDEV.P of Area Price (€)* indicating the average annual electricity price volatility and *Dev from System Price* indicating how much the average area price deviates from the average system price.

To analyze the interactions between the bidding areas, an average importation capacity utilization factor is calculated by calculating the used capacity ratio of the available capacity each hour. The yearly average is summed for each bidding area. The market region SE4 has the highest burden on importing interconnectors in all scenarios. The average demand of interconnector capacity exceeds 40% in FI, SE2, SE3 & SE4 in nearly all scenarios. It can be noted that SE1 goes through the most significant changes when moving from Low Wind scenarios S1 & S2 to High Wind scenarios S3 & S4. NO2 is reducing its imports with the PHS capacity installations in S2 and also the wind share seems to contribute to importing levels; with high wind production levels PHS does not make much difference within the planned grid formation. NO5 is affected by the added PHS capacity in S2 & S4, as observed in the following visualizations of the results.

The most significant differences in the scenarios are observed between Low Wind Scenarios 1 & 2 and the High Wind Scenarios 3 & 4. Large addition of wind power causes the system price to slightly reduce while the currently planned capacity of interconnectors starts going through unsustainable levels of transmission stress.

Table 10. Simulation results for Scenario 1

S1: Low Wind

	FI	SE1	SE2	SE3	SE4	NO1	NO2	NO3	NO4	NO5
ImportMax (MW)	4090	1108	2805	10245	4349	7900	3845	2500	1190	3400
ImportAvg (MW)	1542	97	713	4165	2663	2248	569	900	21	1205
ImportAvg (%)	38 %	9 %	25 %	41 %	61 %	28 %	15 %	36 %	2 %	35 %
Im Avg Max Cap time (%)	21 %	4 %	6 %	4 %	16 %	8 %	5 %	28 %	1 %	13 %
Im Max Line Stress (%)	53 %	6 %	45 %	47 %	99 %	84 %	8 %	60 %	4 %	55 %
Import Total (TWh)	14	1	6	37	23	20	5	8	0	11
ExportMax (MW)	3418	4528	8377	5911	3367	2657	5888	1100	2040	6070
ExportAvg (MW)	1244	1696	3640	2795	1247	460	2963	476	972	3071
ExportAvg (%)	36 %	37 %	43 %	47 %	37 %	17 %	50 %	43 %	48 %	51 %
Ex Avg Max Cap time (%)	18 %	12 %	8 %	16 %	16 %	7 %	35 %	39 %	39 %	41 %
Ex Max Line Stress (%)	47 %	23 %	9 %	85 %	100 %	53 %	76 %	84 %	60 %	61 %
Export Total (TWh)	11	15	32	25	11	4	26	4	9	27
	FI - S1	**SE1 - S1**	**SE2 - S1**	**SE3 - S1**	**SE4 - S1**	**NO1 - S1**	**NO2 - S1**	**NO3 - S1**	**NO4 - S1**	**NO5 - S1**
Share of Wind (%)	18 %	10 %	21 %	10 %	72 %	1 %	7 %	17 %	15 %	1 %
Share of Hydro (%)	22 %	88 %	77 %	12 %	9 %	98 %	93 %	78 %	83 %	97 %
Share of CHP (%)	18 %	2 %	2 %	12 %	18 %	1 %	0 %	5 %	2 %	2 %
Share of Nuclear (%)	42 %	0 %	0 %	66 %	0 %	0 %	0 %	0 %	0 %	0 %
Avg System Price (€)	81,6									
Avg Area Price (€)	86	85	86	87	87	88	87	84	83	86
STDEV.P of Area Price (€)	43,54	41,46	42,30	45,47	45,34	45,39	45,23	39,97	39,32	41,44
Dev from system price (€)	4	3	4	6	6	6	6	2	1	5

Table 11. Simulation results for Scenario 2

S2: Low Wind + PHS

	FI	SE1	SE2	SE3	SE4	NO1	NO2	NO3	NO4	NO5
ImportMax (MW)	**4090**	**1108**	**2924**	**10245**	**4349**	**7900**	**3845**	**2500**	**1190**	**5224**
ImportAvg (MW)	1544	95	710	4163	2663	2246	568	900	20	1221
ImportAvg (%)	38 %	9 %	24 %	41 %	61 %	28 %	15 %	36 %	2 %	23 %
Im Avg Max Cap time (%)	21 %	4 %	6 %	4 %	16 %	9 %	5 %	27 %	1 %	8 %
Im Max Line Stress (%)	53 %	6 %	45 %	47 %	99 %	83 %	8 %	59 %	5 %	55 %
Import Total (TWh)	14	1	6	37	23	20	5	8	0	11
ExportMax (MW)	3418	4528	8300	5931	3367	2657	5888	1100	2040	6145
ExportAvg (MW)	1245	1695	3638	2793	1247	458	2962	476	971	3107
ExportAvg (%)	36 %	37 %	44 %	47 %	37 %	17 %	50 %	43 %	48 %	51 %
Ex Avg Max Cap time (%)	18 %	12 %	8 %	16 %	16 %	7 %	35 %	39 %	39 %	16 %
Ex Max Line Stress (%)	47 %	23 %	8 %	85 %	100 %	53 %	76 %	83 %	59 %	62 %
Export Total (TWh)	11	15	32	25	11	4	26	4	9	27
	FI - S2	**SE1 - S2**	**SE2 - S2**	**SE3 - S2**	**SE4 - S2**	**NO1 - S2**	**NO2 - S2**	**NO3 - S2**	**NO4 - S2**	**NO5 - S2**
Share of Wind (%)	18 %	10 %	21 %	10 %	72 %	1 %	7 %	17 %	15 %	1 %
Share of Hydro (%)	22 %	88 %	77 %	12 %	9 %	98 %	93 %	78 %	83 %	97 %
Share of CHP (%)	18 %	2 %	2 %	12 %	18 %	1 %	0 %	5 %	2 %	2 %
Share of Nuclear (%)	42 %	0 %	0 %	66 %	0 %	0 %	0 %	0 %	0 %	0 %
Avg System Price (€)	81,6									
Avg Area Price (€)	85,61	84,80	85,95	87,43	87,36	87,61	87,37	83,61	82,67	86,34
STDEV.P of Area Price (€)	43,52	41,67	42,34	45,47	45,34	45,40	45,22	39,97	39,33	41,45
Dev from system price (€)	4	3	4	6	6	6	6	2	1	5

Table 12. Simulation results for Scenario 3

S3: High Wind

	FI	**SE1**	**SE2**	**SE3**	**SE4**	**NO1**	**NO2**	**NO3**	**NO4**	**NO5**
ImportMax (MW)	4090	1530	3028	10245	4431	7900	3160	2000	927	3400
ImportAvg (MW)	1826	626	1386	5388	2675	2327	347	694	0	1181
ImportAvg (%)	45 %	41 %	46 %	53 %	60 %	29 %	11 %	35 %	0 %	35 %
Im Avg Max Cap time (%)	30 %	39 %	23 %	6 %	16 %	11 %	2 %	27 %	0 %	12 %
Im Max Line Stress (%)	99 %	86 %	100 %	99 %	99 %	100 %	2 %	100 %	0 %	86 %
Import Total (TWh)	16,04	5,50	12,17	47,33	23,50	20,44	3,05	6,09	0,00	10,37
ExportMax (MW)	3723	4507	8100	6006	3915	2500	6332	1102	2040	5900
ExportAvg (MW)	1514,32	2294,92	4810,07	3481,86	1743,83	578,16	3474,46	966,90	1649,35	3022,28
ExportAvg (%)	41 %	51 %	59 %	58 %	45 %	23 %	55 %	88 %	81 %	51 %
Ex Avg Max Cap time (%)	23 %	24 %	17 %	25 %	25 %	11 %	33 %	85 %	73 %	43 %
Ex Max Line Stress (%)	71 %	45 %	18 %	100 %	100 %	100 %	96 %	100 %	100 %	66 %
Export Total (TWh)	13,30	20,16	42,24	30,58	15,32	5,08	30,52	8,49	14,49	26,55
	FI - S3	**SE1 - S3**	**SE2 - S3**	**SE3 - S3**	**SE4 - S3**	**NO1 - S3**	**NO2 - S3**	**NO3 - S3**	**NO4 - S3**	**NO5 - S3**
Share of Wind (%)	42 %	14 %	30 %	14 %	81 %	3 %	16 %	35 %	35 %	2 %
Share of Hydro (%)	22 %	86 %	70 %	13 %	7 %	97 %	84 %	61 %	65 %	98 %
Share of CHP (%)	10 %	0 %	0 %	5 %	12 %	1 %	0 %	4 %	0 %	1 %
Share of Nuclear (%)	27 %	0 %	0 %	68 %	0 %	0 %	0 %	0 %	0 %	0 %
Avg System Price (€)	79,2									
Avg Area Price (€)	82	81	82	85	85	85	85	79	79	85
STDEV.P of Area Price (€)	39	38	38	43	43	44	43	37	37	43
Dev from system price (€)	3	2	3	6	6	6	6	0	0	6

Table 13. Simulation results for Scenario 4

S4: High Wind + PHS

	FI	**SE1**	**SE2**	**SE3**	**SE4**	**NO1**	**NO2**	**NO3**	**NO4**	**NO5**
ImportMax (MW)	**4090**	**1530**	**3028**	**10245**	**4431**	**7900**	**3160**	**2000**	**927**	**3400**
ImportAvg (MW)	1826	626	1386	5388	2675	2327	347	694	0	1181
ImportAvg (%)	45 %	41 %	46 %	53 %	60 %	29 %	11 %	35 %	0 %	35 %
Im Avg Max Cap time (%)	30 %	39 %	23 %	6 %	16 %	11 %	2 %	27 %	0 %	12 %
Im Max Line Stress	99 %	86 %	100 %	99 %	99 %	100 %	2 %	100 %	0 %	86 %
Import Total (TWh)	16	6	12	47	23	20	3	6	0	10
ExportMax (MW)	3723	4507	8100	6006	3915	2500	6332	1102	2040	5900
ExportAvg (MW)	1514	2295	4810	3482	1744	578	3474	967	1649	3022
ExportAvg (%)	41 %	51 %	59 %	58 %	45 %	23 %	55 %	88 %	81 %	51 %
Ex Avg Max Cap time (%)	23 %	24 %	17 %	25 %	25 %	11 %	33 %	85 %	73 %	43 %
Ex Max Line Stress (%)	71 %	45 %	18 %	100 %	100 %	100 %	96 %	100 %	100 %	66 %
Export Total (TWh)	13	20	42	31	15	5	31	8	14	27
	FI - S4	**SE1 - S4**	**SE2 - S4**	**SE3 - S4**	**SE4 - S4**	**NO1 - S4**	**NO2 - S4**	**NO3 - S4**	**NO4 - S4**	**NO5 - S4**
Share of Wind (%)	42 %	14 %	30 %	14 %	81 %	3 %	16 %	35 %	35 %	2 %
Share of Hydro (%)	22 %	86 %	70 %	13 %	7 %	97 %	84 %	61 %	65 %	98 %
Share of CHP (%)	10 %	0 %	0 %	5 %	12 %	1 %	0 %	4 %	0 %	1 %
Share of Nuclear (%)	27 %	0 %	0 %	68 %	0 %	0 %	0 %	0 %	0 %	0 %
Avg System Price (€)	79,2									
Avg Area Price (€)	81,72	81,28	81,93	85,10	85,10	85,30	84,80	79,35	79,12	85,23
STDEV.P of Area Price (€)	38,82	38,40	38,44	43,48	43,48	43,51	42,86	37,31	37,31	42,99
Dev from system price (€)	2,50	2,07	2,71	5,88	5,89	6,09	5,59	0,14	-0,09	6,02

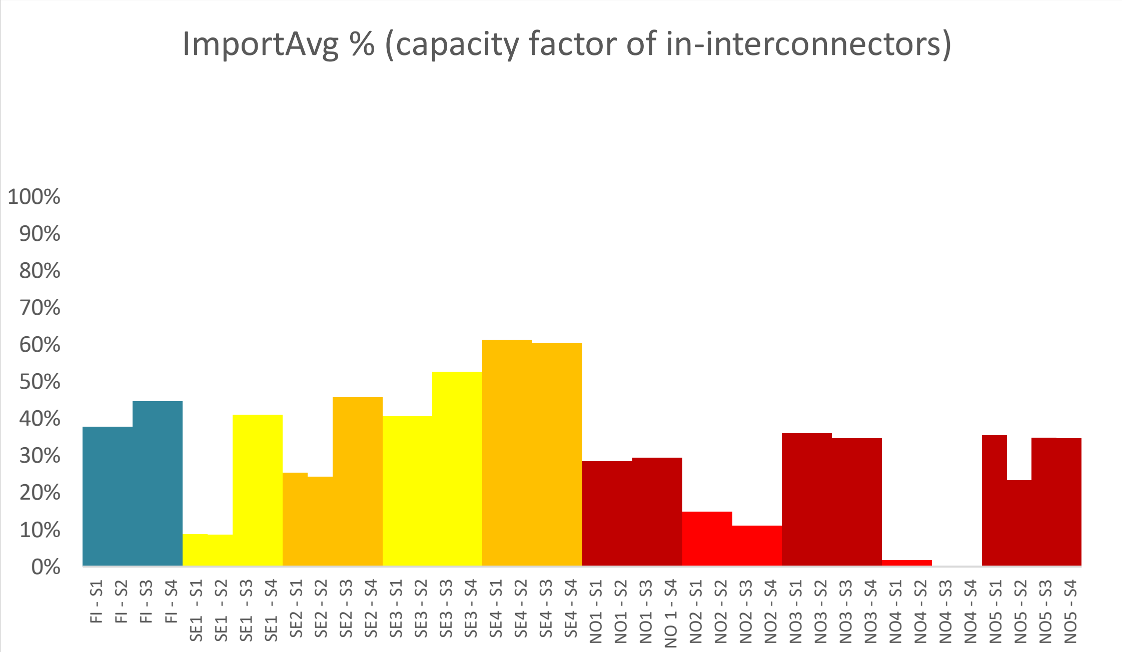

Figure 8. Importing Interconnector Average utilization rate (%)

Similar calculation is performed for the Exporting Interconnector utilization rate for each bidding area and scenario. The most significant changes are observed between the Low Wind scenarios S1 & S2 and the High Wind scenarios S3 & S4. The added PHS capacity does not seem to affect the utilization rate of exporting interconnectors in the modeling results. This can be concluded by observing Figure 9 and the differences between scenarios S1 and S2, which are identical excluding the added PHS capacity. Same principle applies to scenarios S3 and S4, which are identical excluding the added PHS capacity.

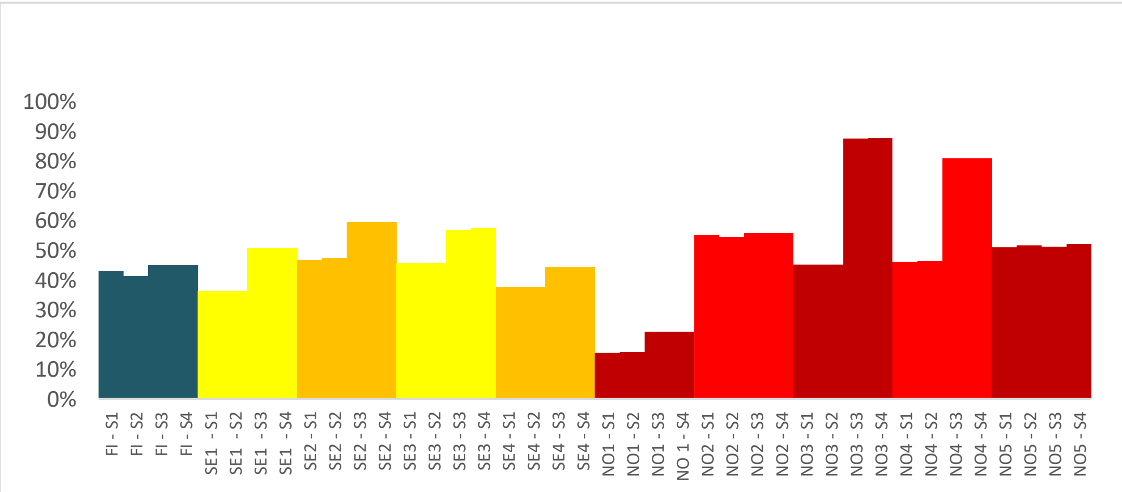

Figure 9. Exporting Interconnector Average utilization rate (%)

The average area price differences can be seen most clearly in Figure 10 between Low Wind and no added PHS scenario S1 and the rest of the scenarios. Increased PHS in S2, increased wind power capacity; and increased wind and PHS capacity all seem to result into very similar system level results in the whole market area; NO4 being the biggest exception. NO4 is affected greatly due to large changes in the PHS production capacity in the neighboring NO-2 and NO-5 areas; and due to the reason that the rather small wind power capacity of 2016 is scaled up heavily in the scenario modeling without sufficient allocation of increase for the transmission network.

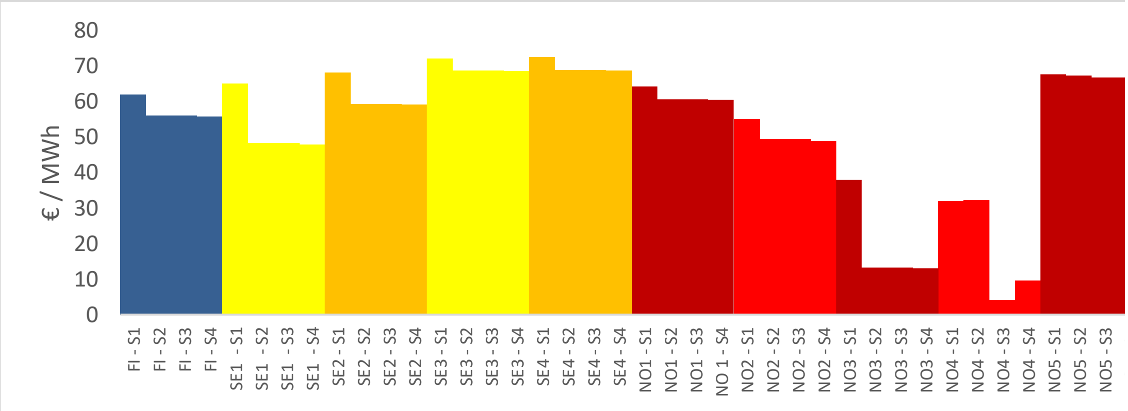

Figure 10. Average Area Price (€/MWh)

The average system price drops 3 % from 81,5 €/MWh to 79 €/MWh between the Low Wind scenarios S1 & S2 and the High Wind scenarios S3 & S4. This result can only be explained with the correlation in the used model between increased wind power and average system price.

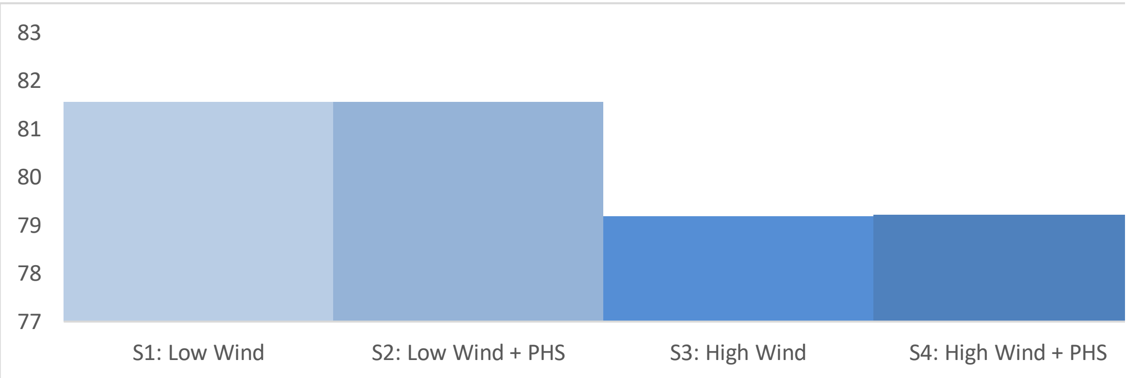

Figure 11. Average System Price (€ / MWh)

Total imports go through the most significant changes in FI, SE1, SE2, SE3, NO2 and NO3. The importation levels in SE1-3 grow when the share of wind is increased. The opposite happens in NO3.

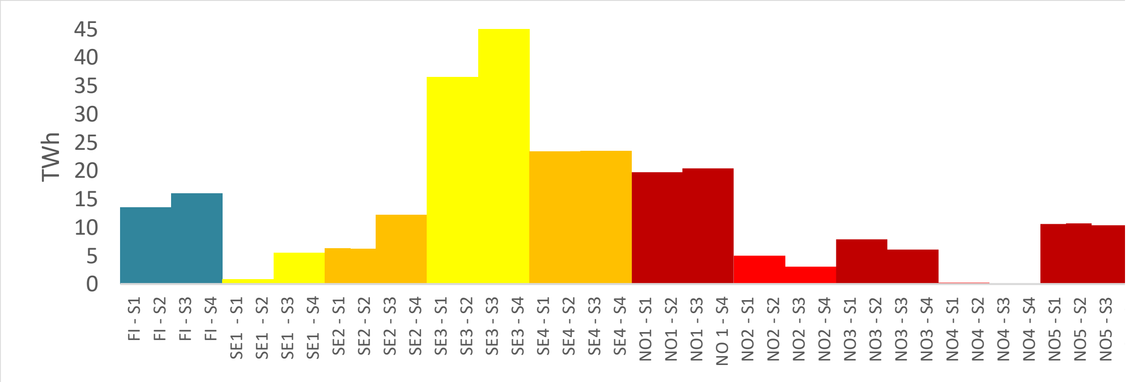

Figure 12. Import Total (TWh)

Also, the amount of exported energy increases in the High Wind scenarios S3 & S4. It can be generally noted that a higher share of wind power leads to increased exchange of electricity between the bidding areas due to the increased need to balance the variable supply and demand.

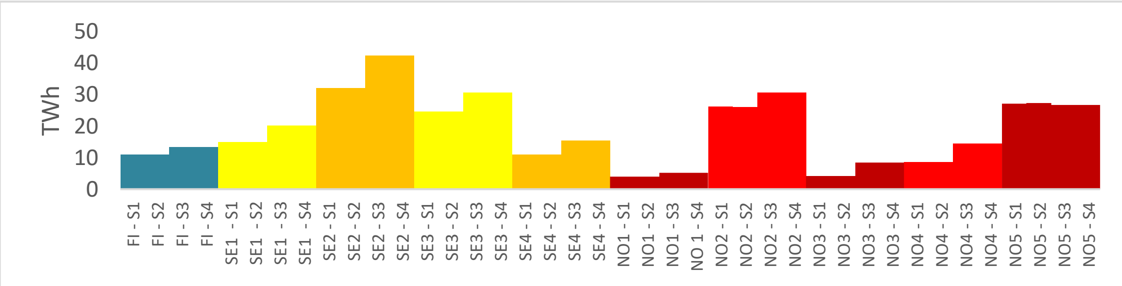

Figure 13. Export Total (TWh**)**

The added PHS capacity does not make significant changes to the importation of electricity between the bidding areas in this simulation. The large wind share seems to significantly affect the maximum usage of importing interconnector capacity in FI, SE1, SE2 and NO2. These impacts can be observed in **Figure 14**. The average maximum capacity usage time reflects the share of time during the year when the interconnector is used at maximum capacity.

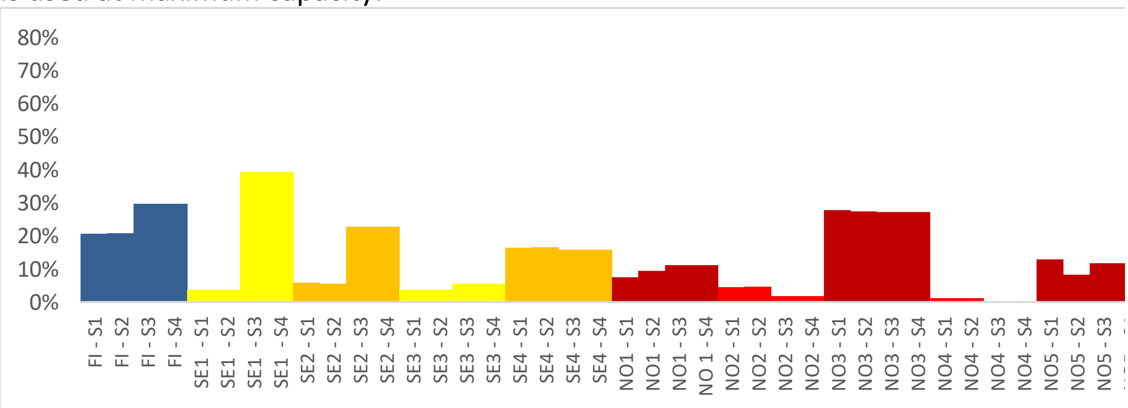

Figure 14. Import average maximum capacity usage time (%)

The ratio of maximum capacity usage between bidding zone export interconnectors can be observed in **Figure 15**. These values are calculated by dividing the number of hours with full capacity utilization with the total number of hours within the observed year. Significant exporting interconnector stress can be observed in all bidding areas except NO1. Highest stress is observed in the high wind scenarios S3 & S4, especially in the bidding zones NO3 and NO4.

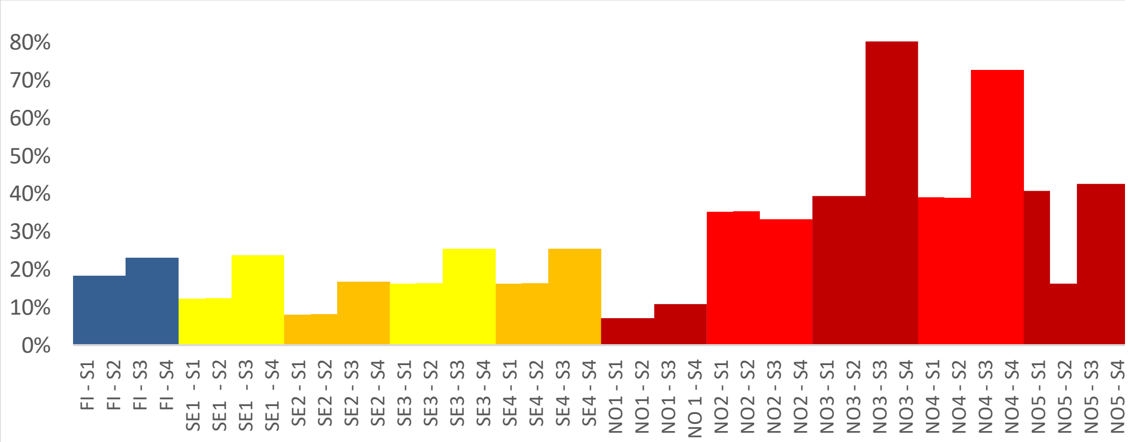

Figure 15. Export maximum capacity usage time (%)

Average usage rate of importing interconnectors is observed in the **Figure 16. Import maximum capacity usage time (%)Error! Reference source not found.**. The maximum capacity usage time of importing interconnectors is calculated the same way as the similar values for exporting interconnectors. Largest changes for maximum usage of importing interconnectors can be observed in bidding zones FI, SE1 and SE2 between the low wind and high wind scenarios.

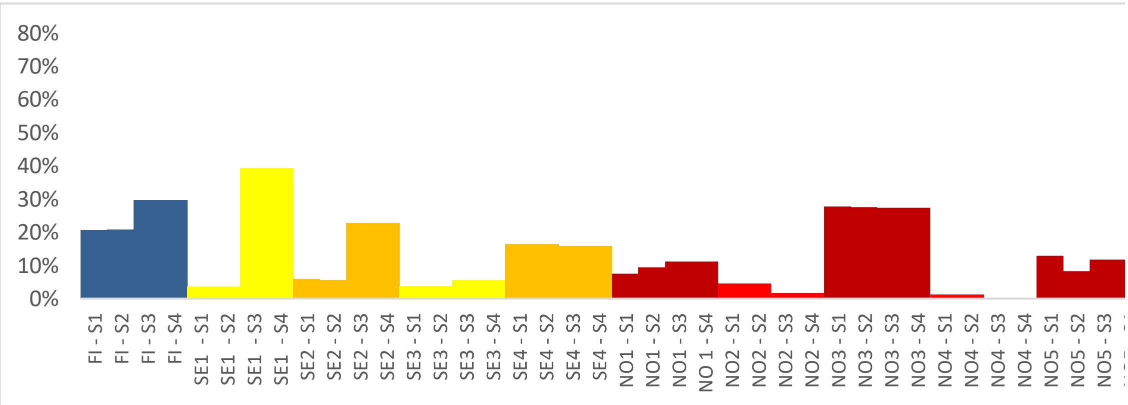

Figure 16. Import maximum capacity usage time (%)

5 Discussion

Projections for scenarios with large geopolitical impacts, timescales of a decade with maturing technologies is always challenging and comes with a variety of uncertain assumptions and potential inaccuracies. The list of potential limitations and sources of inaccuracies in the study includes:

1) *Scenarios assume all wind, hydro, interconnector, and nuclear projects to proceed on the projected schedules.* Effects of potential unplanned faults of network components are not included in this study.
2) *Model simulates the average electricity demand and rainfall conditions of 2016 and wind rates of 2014.* These figures are likely to deviate annually from the used averages, which causes deviation between measured and simulated results.
3) *The price of auctioned EU carbon emissions permits will be projected based on a single scenario, which may not represent the reality in 2030.* The market impacts of emission permits and other legislative price components or operational restrictions are not included in this study.
4) *Potential efficiency improvements in all power plants are neglected.* Significant efficiency improvements of generation technologies may increase their market competitiveness by 2030.
5) *Potential increase in ramping flexibility of power plants are neglected.* Increase in ramping capacity of existing capacity would increase the competition in multi-market operations.
6) *No new district heat grids or heat pump capacity are developed.* It may be a valid alternative scenario that Nordic countries aim to decarbonize their energy systems by reinforcing or developing new flexible district heating networks, which would also affect the electricity market dynamics.
7) *The electricity market bidding areas stay the same.* Potential rearrangements in the bidding zoning principles or division could affect the electricity prices in bidding zones without changes in the generation or interconnector capacities.
8) *No significant changes to regulation are done.* In reality multiple simultaneous regulative development processes have taken place already and plenty of regulation-based adjustment in the energy markets can be expected during the following decade. Changes in taxonomy, taxation, subsidy structures, emission permit pricing and bans on fuel types may change the cost structures and thus competitiveness of generation mixes.
9) *No energy storage solutions beyond PHS implemented.* The price development of electric batteries, especially lithium-ion batteries make it seems highly likely, that more competition for the multi-market operations will emerge by 2030.
10) *No changes to electricity taxes or transmission rates.* These figures are likely to change within a decade and some governments are already publishing initial claims to increase the market competitiveness of clean electricity via electricity tax cuts. National electricity or transmission tax rates are not included in this modeling.

6 Conclusions

The aim for this study is to evaluate the potential transmission impacts of high wind and PHS generation capacity increases in the Nordic Electricity Market. The modeling results show that actualizing the ambitious VRES increase goals in the Nordic Electricity Market will lead into high levels of interconnector stress. The results also show that even the heavy increase in the PHS capacity in the most potential areas would not significantly reduce the interconnector stress levels. It was not modeled if the increase in PHS capacity would alleviate interconnector congestion combined with enforced transmission capacity through the PHS regions.

The simulation results indicate that the current development pathways of wind power and interconnector capacity development are not yet aligned sufficiently to create the maximum economic overall benefits for the Nordic electricity market area. According to the used sources, the development plans for wind power capacity increases in the Nordic electricity markets within the next 10 years exceed the simulated needs of transmission network capacity improvements. Since the development cycles of VRES generation capacities are generally much shorter than development cycles of new interconnector capacity; the mid- and long-term goals of both generation and transmission capacity improvements should be considered a decade ahead of implementation. It seems to be a matter of high importance to align the Nordic TSO interconnector capacities to match the planned wind power development plans. This collaboration is conducted through the national expert bodies and under international organizations such as ENTSO-E.

Increased transmission capacity enables the VRES resources to be utilized within the grid without the need for energy storage. This study does not answer to the question that which alternative is more likely to be more cost-efficient, increasing the interconnector capacity or building a network of quickly cost-reducing storage solutions. The study results show that increasing the PHS capacity in the Nordic electricity markets is unlikely enough to solve the interconnector congestion challenge of high increase in VRES generation capacity. The VRES production profile – especially with wind power – varies according to the local conditions and weather patterns. The uneven production of VRES enables the grid to transmit the surplus energy from one production area to another. The more interconnector capacity different electricity bidding zones have between each other, the more variable resources can be balanced by trading among the bidding areas.

Design of flexibility markets, market mechanisms and price formations do not yet support the scale of improvements required for the vision of the future European energy system (Harby 2019). The increased volatility of residual demand in the high VRES scenarios will require large flexibility resources from increased transmission, energy storage, quick-responding high-capacity generation and demand flexible technologies.

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APPENDIX 1 - Modeled Nordic Interconnector Capacities (ENTSO-E Transparency Platform 2020)

NTC	FI	SE1	SE2	SE3	SE4	SE	NO1	NO2	NO3	NO4	NO5	NO	DK1	DK2	DK	EE	LV	LT	DE	PL	NL	BY	GB
FI	0	1100	0	1200	0	2300	0	0	0	90	0	90	0	0	0	1016	0	0	0	0	0	0	0
SE1	1500	0	3300	0	0	0	0	0	0	600	0	600	0	0	0	0	0	0	0	0	0	0	0
SE2	0	3300	0	7300	0	0	0	0	1000	300	0	1300	0	0	0	0	0	0	0	0	0	0	0
SE3	1200	0	7300	0	5300	0	2095	0	0	0	0	2095	680	0	680	0	0	0	0	0	0	0	0
SE4	0	0	0	2000	0	0	0	0	0	0	0	0	0	1300	1300	0	0	700	615	600	0	0	0
SE	2700	0	0	0	0	0	2095	0	1000	900	0	3995	680	1300	1980	0	0	700	615	600	0	0	0
NO1	0	0	0	2145	0	2145	0	2200	500	0	300	0	0	0	0	0	0	0	0	0	0	0	0
NO2	0	0	0	0	0	0	3500	0	0	0	500	0	1632	0	1632	0	0	0	0	0	700	0	0
NO3	0	0	600	0	0	600	500	0	0	200	0	0	0	0	0	0	0	0	0	0	0	0	0
NO4	90	700	250	0	0	950	0	0	1000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NO5	0	0	0	0	0	0	3900	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NO	90	700	850	2145	0	3695	0	0	0	0	0	0	1632	0	1632	0	0	0	0	0	700	0	0
DK1	0	0	0	740	0	740	0	1632	0	0	0	1632	0	590	0	0	0	0	1780	0	0	0	0
DK2	0	0	0	0	1700	1700	0	0	0	0	0	0	600	0	0	0	0	0	585	0	0	0	0
DK	0	0	0	740	1700	2440	0	1632	0	0	0	1632	0	0	0	0	0	0	2365	0	0	0	0
EE	1016	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	829	0	0	0	0	0	0
LV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	879	0	1234	0	0	0	0	0
LT	0	0	0	0	700	700	0	0	0	0	0	0	0	0	0	0	684	0	0	500	0	0	0
RU	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DE	0	0	0	0	615	615	0	0	0	0	0	0	1500	600	2100	0	0	0	0	0	0	0	0
PL	0	0	0	0	600	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NL	0	0	0	0	0	0	0	700	0	0	0	700	0	0	0	0	0	0	0	0	0	0	0
BY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0